BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Approval of Demand Response Programs, Goals and Budgets for 2009 through 2011.	Application 08-06-001 (Filed June 2, 2008)
Application of San Diego Gas & Electric Company (U 902 M) for Approval of Demand Response Programs and Budgets for Years 2009 through 2011.	Application 08-06-002 (Filed June 2, 2008)
Application of Pacific Gas and Electric Company for Approval of 2009-2011 Demand Response Programs and Budgets (U39E).	Application 08-06-003 (Filed June 2, 2008)

OPENING BRIEF
OF THE DIVISION OF RATEPAYER ADVOCATES

****[REDACTED VERSION]****

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January 28, 2009

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I. INTRODUCTION

Pursuant to Rule 13.11 of the Commission's Rules of Practice and Procedure, and the schedule set forth in the November 10, 2008 Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling, the Division of Ratepayer Advocates (DRA) hereby submits this Opening Brief in the Applications of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) (collectively, the "utilities" or "IOUs") to approve their respective 2009-2011 Demand Response (DR) Program

Budgets. The utilities collectively seek approval of $439 million[1] for the upcoming 2009-2011 Demand Response cycle.

A. The Commission Invested Over $561.3 Million Thus Far in Demand Response, Excluding Costs Related To Advanced Metering Initiatives

Utility-run demand response programs have grown at a significant rate over the past several years due in large part to the July 2006 heat wave, but at a substantial cost to ratepayers. Since 2006, the Commission approved over $561.3 million in ratepayer funding for demand response programs, excluding costs already authorized in the utilities' separate Advanced Metering Initiatives (AMI).[2] In past proceedings, the Commission has set aside the issue of whether a specific DR program is cost-effective.[3] Even after authorization of the 2006-2008 DR programs and budgets, the Commission justified additional DR resources based on the need for "additional insurance," beyond the amount needed to meet the utilities' planning reserve margins.[4] In other cases, the Commission found reassurance in specific program designs the Commission believed offered adequate ratepayer protection.[5] In short, the Commission did not expressly require programs be cost-effective in order to encourage new market players and customers to demand response. However, this policy no longer needs to be followed.

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[1] Ex. 314, p. 5, line 18.

[2] Total costs include approved budgets of the following: 2006-2008 DR program cycle, D.06-03-024: PG&E ($108.7 million), SCE ($101 million), and SDG&E ($52.6 million). Five aggregator contracts for PG&E (approx. $46 million over the 5 year terms) and one for SCE xxxxxxxxxxxx, D.07-05-029. *See* Exh. 2 (PG&E Direct Testimony) in A.07-02-032, p. ES-2; and Exh. C-316, p. 1, line 13. PG&E's AC Cycling Program ($178.8 million), D.08-02-009. SCE's Summer Discount Plan (AC Cycling) ($18.4 million), Resolution E-4028. Four SCE aggregator contracts (approx. xxxxxxx), D.08-03-017. D.06-11-049 adopted changes to 2007 DR programs, but no additional funding was requested.

[3] D.07-05-029, pp. 13-14.

[4] *Id*. at pp. 14-15.

[5] D.08-03-017, p. 13.

The current economic climate requires the Commission to carefully weigh its policy that places demand response as a preferred loading order resource with its responsibility to prudently invest ratepayer funds in reliable and cost-effective DR.[6] The time of seeking "new and innovative" demand response is at a point where costs must be reasonable in relationship to the benefits they provide, and program participants must be held accountable for their load drop commitments.[7] The utilities now have sufficient experience in demand response that the Commission can make an informed decision on whether a program should be continued, redesigned, or eliminated. Furthermore, in contrast to past proceedings, the utilities present their cost-effectiveness analysis using the same methodology—the Consensus Framework[8]—rather than using the cost-effectiveness protocols developed for energy efficiency programs and/or using their own proprietary models. It is now possible to compare the assumptions and benefit-cost ratios of similar DR programs across the three utilities to provide a more comprehensive evaluation of the Applications.

B. Summary of Recommendations: DRA Ranking Mechanism

As discussed in the Prepared Testimony of Sudheer Gokhale, DRA noted the difficulty of evaluating the utilities' proposals for the current cycle.[9] Although demand response has been growing at a rapid pace, the Commission's corresponding DR policies have been slow to evolv: (1) the Commission has yet to approve final cost-effectiveness protocols, establish DR goals for 2009 and beyond, and describe a long-term DR vision; (2) the *ex-post* studies on 2008 DR programs, expected in

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[6] Section 454.5 (b)(9)(C) of the Public Utilities Code states, "The electrical corporation will first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible."

[7] *See* Statement of Commissioner Chong, 1 RT 4, lines 13-23.

[8] Pending adoption of final cost-effectiveness protocols in R.07-01-041.

[9] Ex. 314, pp. 10-11.

Spring 2009, would have provided more accurate and reliable *ex-ante* estimates of load impacts for the next DR cycle; (3) CAISO guidance documents regarding integration of demand response into MRTU Release 1 in Spring 2009 and the Market and Performance (MAP) are still developing; (4) the Commission is evaluating the need for and the desirable level of emergency/interruptible programs in Phase 3 of Rulemaking 07-01-041; (5) the Commission may address direct participation by aggregators in CAISO's wholesale markets as directed by FERC Order No. 719; and (6) the IOUs' Demand Side Management (DSM) integration plans are still pending.[10]

Given these uncertainties, DRA developed a sensible ranking mechanism to screen the utilities' DR proposals. DRA's proposed mechanism categorizes utilities' proposals consistent with the Commission's demand response objectives. This initial screening process is as follows:

> **Rank 1:** Programs included in this rank will have a Total Resource Cost Benefit/Cost (TRC B/C) ratio greater than 1.0, and are likely to provide *ex-post* load impacts close to the *ex-ante* estimates used in the utilities' cost-effectiveness calculations, and are either furthest along or have the greatest potential of being integrated with CAISO's MRTU in a cost-effective manner.
>
> **Rank 2:** Programs included in this rank will have the potential to have a TRC B/C ratio greater than 1.0 and are likely to provide *ex-post* load impacts close to the *ex-ante* estimates used in the utilities' cost-effectiveness calculations. These programs could be integrated with CAISO's MRT, but the current estimates of costs of such integration appear to be excessive.
>
> **Rank 3:** Programs included in this rank will have the potential to have a TRC B/C ratio greater than 1.0 and are likely to provide *ex-post* load impacts close to the *ex-ante* estimates used in the utilities' cost-effectiveness calculations, but could not be integrated with CAISO's MRTU because of the specific structure of the programs.
>
> **Rank 4:** Programs included in this rank have an extremely low TRC B/C ratio. Some of these programs also have a very poor record of providing actual load reduction close to their contractual commitments. These programs are generally not self-sustaining and do not justify continued ratepayer support.

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[10] IOUs were to refile their 2009-2011 Energy Efficiency (EE) portfolio applications on January 15, 2009 which included Demand Side Management (DSM) integration plans, as required by D.08-09-040. This has been further delayed to February.

DRA's initial screen prioritizes approval for DR programs that are Ranked 1 and 2.[11] Programs that fall under Rank 3 (*i.e.,* BIP) should be conditionally approved, pending a new application or petition for modification to justify continuation of the programs after 2009, or until the Commission adopts a final decision in Phase 3 of the Rulemaking 07-01-041 to determine the appropriate level of interruptible programs, such as BIP. For programs receiving a Rank 4 designation (*i.e.,* PG&E's BEC/ABEC program and SCE's proposed day-ahead aggregator contracts), DRA recommends discontinuation or rejection by the Commission.

C. DRA's Ranking Mechanism To Screen The Utilities' Proposed Demand Response Programs Is Reasonable

In rebuttal testimony, PG&E, SCE, and SDG&E criticize DRA's screening mechanism, arguing that it is not as comprehensive as the evaluation criteria described in the November 10, 2008 Assigned Commissioner and Administrative Law Judge Scoping Memo and Ruling ("Scoping Memo"), and is "insufficient to use to evaluate DR programs."[12] Both SCE and SDG&E claim that DRA's method treats cost-effectiveness as a requirement, contrary to the Scoping Memo. DRA disagrees for several reasons:

First, although the Scoping Memo lists thirteen evaluation criteria, not all of the criteria should be given equal weight as the Scoping Memo does not specify which are most important. For example, "Simplicity/Understandability" (Criterion #10) is not close in importance as cost-effectiveness (Criterion #1) or track record of performance (Criterion #2). Even critics of DRA's mechanism, such as SCE,

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[11] See Ex. 314, pp. 14-15. For PG&E, Rank 2 programs are: Peak Choice, Capacity Bidding Program (CBP), Critical Peak Pricing (CPP), and Demand Bidding Program (DBP). For SCE, Rank 2 programs are: CBP, CPP, DBP, Agricultural Pumping Interruptible, and Summer Discount Plan. For SDG&E, Rank 2 programs are: CBP, CPP, and Technical Assistance/Technical Incentives.

[12] Ex. 202, p. 3-3, lines 23-28; Ex. 7, p. 27, lines 16-20; Ex. 122, p. MMS-9.

conceded in hearings that the weighting of the different criteria has not been specified by the Commission.[13]

Second, the cost-effectiveness analysis captures most of the evaluation criteria listed in the Scoping Memo Ruling, as DRA explains below. DRA's proposed screening mechanism also considers integration of DR programs with the CAISO's MRTU (Criterion #6) and the programs' ability to demonstrate *ex-post* performance consistent with the utilities' *ex-ante* estimates (Criterion #2 and #3, discussed below).

Third, DRA's proposed mechanism recommends approval of most of the programs, although it also appropriately recommends the Commission require utilities' to submit updates, as most of the time-dependent uncertainties will be resolved in 2009. Besides inconvenience, the utilities have not presented any compelling reasons as to why such updates are unnecessary. These reports are essential to assure that DR programs will provide the benefits ratepayers expect and are entitled to receive.

Finally, DRA's proposed ranking mechanism reflects Commissioner Chong's expectations of DR, as stated at the commencement of hearings on January 6, 2009. These expectations include:

> (1) The cost of these programs needs to be reasonable;
>
> (2) Mechanisms need to be put in place to make sure customers follow through with their demand response commitments;
>
> (3) High priority should be placed on continuing to integrate demand response into the ISO's market.
>
> (4) Dual participation in dynamic pricing and demand response programs should be structured to avoid overpaying or underpaying customers for reducing demand.[14]

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[13] 4 RT 602, lines 17-18 (Combs/SCE).

[14] 1 RT 4, line to 5, line 23 (Cmmr. Chong/CPUC).

1. The Cost-Effectiveness Analysis Captures Most of the Evaluation Criteria Listed in the Scoping Memo Ruling

Cost-effectiveness should be considered *the most important* factor that reveals whether further analysis is warranted. SDG&E opposes DRA's mechanism, but "supports the idea that there should be metrics used to determine whether programs should be approved or not, foremost should be cost effectiveness."[15] The February 27, 2008 ALJ Ruling directed the utilities to use the Consensus Framework[16] in order to facilitate a comprehensive examination of all DR programs in these Applications. The November 10, 2008 Scoping Memo also states that cost-effectiveness is one of many important factors in evaluating proposed activities.[17] The cost-effectiveness analysis helps determines whether costs are reasonable. But in fact, the cost-effectiveness analysis also takes into account most of the thirteen criteria[18] listed in the Scoping Memo.

For example, the second and third criteria, "**track record of performance**" and "**projected future performance**" are considered in the *ex-post* and *ex-ante* load impact estimations provided by the utilities. For event based programs, the Load Impact Protocols require that the *ex-ante* load impact estimates be based on *ex-post* analysis of existing programs whenever the existing data and characteristics of the program allow for such an approach.[19] As such, *ex-ante* load impact estimates directly feed into the cost-effectiveness analysis. Where utilities were unable to complete an

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[15] Ex. 122, p. MMS-9, lines 19-22.

[16] February 27, 2008, *Administrative Law Judge's Ruling Providing Guidance On Content And Format Of 2009-2011 Demand Response Activity Applications,* p. 26.

[17] See November 10, 2008 Scoping Memo and Ruling, p. 10, which states, "While this framework is not as broad as the subsequent protocols proposed by CPUC staff…it does provide a useful estimate for examining the cost-effectiveness of programs."

[18] Scoping Memo, pp. 10-12.

[19] Ex. 1, p. 141, lines 19-21.

ex-post evaluation, DRA reviewed the program's track record of performance, as it did with regard to SCE's aggregator contracts in the Prepared Testimony of Yuliya Shmidt.[20] In addition, DRA compared *ex-ante* estimates of similar programs across the IOUs to assess whether those estimates seemed reasonable[21]

The fourth criterion in the Scoping Memo, "**cost**," is certainly a factor in the cost-effectiveness analysis. The resulting Total Resource Cost test benefit-cost ratio is a useful tool in studying the value of a particular program.

The fifth criterion, "**flexibility or versatility**," is described as:

> "[w]hether a program can be called under a variety of circumstances, or only in very rare or specialized situations. For example, does the program have multiple triggers? Can it be called on a price responsive basis for simply day to day resource dispatch, as well as for contingency matters such as emergencies? Can it be called on non-summer months to respond to generator outages?"[22]

This is captured in the B-Factor by SCE (and in other forms by PG&E and SDG&E), which is used in the calculation to determine avoided generation capacity benefits for the cost-effectiveness analysis. As SCE's Prepared Testimony explains,

> DR capacity benefits also have a time dimension. Programs that can be called on short notice or dispatched only when needed are a valuable resource to the utility. This value is represented by the B-Factor. Programs with a very limited number of calls and day-ahead notification requirements have a smaller B-Factor than a program with unlimited calls and availability on short notice.[23]

The sixth criterion, "**adaptability to changes in the structure of the electricity market**," is a component of DRA's ranking mechanism, which factors

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[20] Ex. 316 and C-316.

[21] Ex. 314.

[22] Scoping Memo, p. 11.

[23] Ex. 1, p. 208, lines 24-27.

whether a proposed DR program has the potential of being fully integrated with the California Independent System Operator's (CAISO) Market Redesign and Technology Upgrade (MRTU) in a cost-effective manner.

"**Locational value**," the seventh criterion, or whether a program can be called by a specific location, is also a consideration in the cost-effectiveness sensitivity analysis, in evaluating whether deferred Transmission & Distribution (T&D) Capacity benefits should be allocated.

The Scoping Memo also lists "**Environmental benefits**" as an item for consideration. SCE calculates the GHG benefits in the year 2012 and beyond in its cost-effectiveness analysis.[24] Current protocols give environmental benefits a relatively small, very marginal value in analysis.

Two factors, "**integration with AMI, smart grid, and emerging technology**" and "**contribution to existing State/CPUC policy/goals**" are not specifically addressed in a cost-effectiveness analysis. However, these factors cannot be meaningfully evaluated until the Commission's policies and goals with respect to AMI and the smart grid are more clearly defined in other proceedings.[25] DRA addresses contribution to existing/State/CPUC policy/goals in Section II.C.4, below.

The remaining factors listed in the Scoping Memo—"**consistency of offerings throughout the state**," "**simplicity/understandability**," and "**customer acceptance and participation**"—are implicitly reflected in a cost-effectiveness analysis, as the utilities' success in addressing these factors ultimately reflects in customer enrollments and participation in the program. This, in turn, provides the basis for load impact estimates used in the cost-effectiveness analysis.

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[24] Ex. 1, p. 215, line 5.

[25] See December 22, 2008 *Final Decision Re Order Instituting Rulemaking Smart Grid Policies* in R.08-12-009.

2. DRA’s Ranking Mechanism Does Not Treat Cost-Effectiveness As A Requirement

DRA also disagrees with SCE’s and SDG&E’s claim that the screening mechanism treats cost-effectiveness as a requirement, contrary to the Scoping Memo. DRA’s ranking system is not as rigid as the IOUs describe it to be. For example, Rank 2 does not require that a program have a TRC B/C ratio over 1.0, but simply gauges whether the program has high *potential* to be cost-effective, after consideration of other factors, such as its adaptability to fit within MRTU. Accordingly, DRA’s ranking system does not treat cost-effectiveness as a hard line requirement—if this were the case, DRA would not recommend a Rank 2 designation for PG&E and SCE’s Capacity Bidding Program (CBP), which each have a TRC B/C ratio of 0.89.[26] Additional factors, as described in the Prepared Testimony of Sudheer Gokhale, contribute to DRA’s recommendation for program approval.[27]

Although the utilities reject DRA’s approach, no other party has offered an alternative method for evaluating programs. In the absence of any coherent proposals from other parties, and if DRA’s proposal is not used, the Commission will again face the dilemma of either accepting all proposed programs or rejecting some of them in an arbitrary manner. The Consensus Framework is the only device the Commission has to properly evaluate cost-effectiveness, and it should be afforded the appropriate weight, consistent with DRA’s ranking mechanism.

Ultimately, DRA recommends a Rank 2 approval for most of the proposed demand response programs based on its ranking mechanism. DRA’s analysis shows that the Rank 3 or 4 programs contain deficiencies or features that conflict with the demand response goals Commissioner Chong set at the January 6, 2009 hearing. DRA discusses its recommendations for programs that it assigns either a Rank 3 or 4, on a case-by-case basis below.

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[26] Ex. 314, p. 21.

[27] *See* Ex. 314, pp. 21-24.

II. UTILITY-SPECIFIC PROGRAMS

A. PG&E's Proposed BEC/ABEC Programs Should Not Be Approved Because They Cannot Be Cost-Effective Under Any Foreseeable Circumstance

For its Business Energy Coalition ("BEC") and Automated Business Energy Coalition ("ABEC"), PG&E's forecasted budget of $15.4 million[28] ($5.2 million for BEC and $10.2 million for ABEC) for the three- year cycle is unreasonable. In the most optimistic of scenarios, a maximum allowance of 100% T&D benefits gives a TRC B/C ratio for the BEC and ABEC programs only 0.25 and 0.15, respectively.[29] Even taking into consideration the program's potential as Proxy Demand Response under the CAISO's Market and Performance (MAP) in 2010, PG&E lists costs of implementation and the presence of Direct Access customers as barriers to integration with MRTU.[30] Furthermore, there is no reason why both BEC and ABEC customers cannot participate in either PG&E's Capacity Bidding Program (CBP) or in the more flexible PeakChoice program to provide the same or more reduction at much reduced cost. DRA also believes the availability of such customers for CBP and PeakChoice would likely increase the cost-effectiveness of those programs as marketing and other administrative costs are spread over a larger customer base. For all these reasons, DRA designates a Rank 4 recommendation.

PG&E explains it understated the ABEC program cost-effectiveness because (1) it forecasted load impacts using 2007 activity, even though the observed 2008 activity in BEC was much higher; and (2) the new automation costs are included, but the performance and reliability benefits are not included in the cost-effectiveness analysis.[31] PG&E also explains the low BEC B/C ratio because PG&E used the actual

[28] Ex. 201, p. 7-2, Table 7-1.

[29] Ex. 201, p. 6-21. The B/C ratios with zero T&D benefits for BEC is 0.17 and ABEC is 0.10.

[30] Ex. 314, p. 32, lines 9-11.

[31] Ex. 202, p. 2-22, lines 7-22.

performance of CBP to run a simple scenario analysis for BEC, and compares the load impacts estimates of 3.6 MW to the actual performance of BEC in 2008 as between 6.5 MW to 18.5 MW.[32]

While the claimed 2008 actual performance levels are encouraging, PG&E did not provide an updated B/C ratio regarding its suggestions that BEC and ABEC are more cost-effective than indicated in its application. Given the extremely low cost-effectiveness ratios that PG&E currently reports, DRA doubts these improvements to benefit-cost ratios would justify moving the program to a higher ranking under the screening mechanism.

DRA also notes the initial purpose of the BEC program was to target "hard-to-reach" customers whose needs had not been met by other demand response programs.[33] The program later was expanded to 50 MW by PG&E after the July 2006 heat storm due to a directive by the Commission to augment DR programs for 2007 and 2008. In *Opinion Modifying Resolution E-4079 and D.06-11-049,* the Commission stated that to **expand** the BEC program,

> [w]ould require the consideration of facts and issues…e.g., the design of the BEC program, the relative cost and effectiveness of the BEC program, and the impact of a broader BEC program scope on the aggregator demand response contracts.[34]

The Commission stated one of the main attractions of the program was the dispatchability it can provide the system, and the "additional level of customer service and instruction."[35]

The Commission should reject both BEC and ABEC, and invest the $15.4 million in ratepayer funding in other, more cost-effective programs, such as those

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[32] Ex. 202, p. 2-22, lines 23-33.

[33] Resolution E-4079, pp. 7-8.

[34] D.07-12-048, p. 8.

[35] *Id.*

programs provided through third party aggregators. In doing so, the original intent of creating the BEC program would not be lost. Third-party aggregators have a greater role in the market today than they did when the Commission first approved the BEC program in D.05-01-056. Aggregators fill the role of targeting "hard-to-reach" customers by offering additional levels of customer service and instruction in the various demand response offerings they provide. PG&E could utilize its existing AMP program, or target its upcoming RFP for additional aggregator contracts, to attract these customers. More recent aggregator contracts (such as the ones SCE proposes in this case) now offer terms for year-round capacity and local dispatchability. As a result, rejection of the BEC and ABEC programs should encourage competitive third-party offers that can result in more cost-effective products.

In D.06-11-049, responding to an argument that utilities are not in the business of designing demand response programs and that third-party providers may be more creative and cost-effective in their efforts, the Commission stated, "We agree with the parties who suggest demand aggregators may encourage innovative and less costly demand response programs."[36] PG&E's ratepayers and BEC and ABEC customers would be better served by DR aggregators who are increasingly playing a major role in California's DR market.

B. DRA Reached a Settlement in Principle Regarding SCE's Proposed Contracts With EnerNOC and AER

In the Prepared Testimony of Yuliya Shmidt, DRA recommends rejection of all four of SCE's proposed third-party contracts in this proceeding.[37] At this time, DRA reached a settlement in principle with SCE regarding the proposed day-of contracts with EnerNOC Inc. and Alternate Energy Resources Inc. (AER). A settlement conference, pursuant to Rule 12.1 of the Commission's Rules of Practice

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[36] D.06-11-049, p. 16.

[37] *See* Ex. 316 and C-316, pp. 5-16.

and Procedure, was held with each of the settling parties in attendance on January 22, 2009. DRA anticipates the parties will file a joint motion to approve the settlement on or before February 11, 2009. In the event that such a motion is not filed within the timeframe allowed by Commission Rules[38], DRA reserves the right to maintain its position stated in its prepared testimony with respect to the proposed EnerNOC and AER contracts, and may seek the opportunity to respond to rebuttal testimony on those issues.

C. SCE's Proposed Aggregator Contracts with ECS and ECI Should Not Be Approved

SCE seeks approval of two day-ahead aggregator agreements, an Energy Curtailment Specialists, Inc. (ECS) contract, and an Energy Connect, Inc. (ECI) contract. Of the four proposed contracts, these two contracts have, by far, the lowest cost-effectiveness TRC B/C ratios.[39] For this and other reasons explained below, DRA places these specific contracts in Rank 4 and recommends the Commission reject SCE's request.

1. DRA's Rank 4 Recommendation Is Justified

DRA agrees that because the program trigger is at SCE's discretion, the proposed contracts have the potential to fully integrate into MRTU, an important factor within DRA's ranking system to evaluate DR programs. However, additional factors apply to justify a Rank 4 designation.

For clarification, DRA notes that SCE's Exhibit C-11, "Demand Response Cost-Effectiveness Comparison" is inaccurate and conflicts with the facts SCE provided to the Commission in its December 14, 2007 Supplemental Testimony in A.07-10-013 (Exhibit C-309), and in its answer to Question 1 of the July 28, 2008 Data Response to DRA (Exhibit C-303). For instance, SCE's table in Exhibit C-11

[38] Rule 12.1 permits a settlement proposal to be filed within 30 days of the last day of hearings.

[39] *See* Ex. C-303, Attachment to Question 1 (first three pages showing sensitivity analysis of TRC B/C ratios).

provides renegotiated TRC results for a contract that was never renegotiated and was, in fact, approved by D.08-03-017. Moreover, the TRC results provided are incorrect. Finally, nowhere in the A.07-10-013 record does SCE provide a 50 percent T&D sensitivity analysis for those contracts. Thus, the Commission should give this Exhibit the appropriate weight by disregarding the information contained therein.

SCE's argument that the renegotiated contracts improved cost-effectiveness, as compared to the contracts' previous structure in A.07-10-013, is questionable. Of the four contracts, SCE's analysis shows the two day-ahead contracts have the lowest cost-effectiveness TRC B/C ratios:

Table 1: Rejected Contracts in A.07-10-013

TRC Benefit-Cost Ratio[40]	No T&D benefits	100% T&D benefits[41]
ECS DA	xxxx	xxxx
ECI DO	xxxx	xxxx

Table 2: SCE Renegotiated Contracts

TRC Benefit-Cost Ratio[42]	No T&D benefits	50% T&D benefits
ECS DA	xxxx	xxxx
ECI DA	xxxx	xxxx

As shown above, the renegotiated contracts' cost-effectiveness ratios improved only slightly. DRA does not believe these contracts even have the *potential* to be cost-effective for two reasons: (1) SCE has not demonstrated the contracts meet the

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[40] *See* Ex. C-309, Confidential Appendix A.

[41] SCE's Supplemental Testimony in A.07-10-013 (Ex. C-309) does not provide a sensitivity analysis using a 50% allocation of deferred T&D benefits.

[42] *See* Ex. C-303, Attachment to Question 1.

requirements specified in the Consensus Framework to qualify for any T&D benefits; and (2) SCE simply ignores the track record of similar aggregator contracts with SCE and, in the cost-effectiveness analysis, assumes that the aggregators will always provide 100 percent of contracted capacity. But, as DRA demonstrates in its prepared testimony, actual load reductions provided by the existing contracts averaged 41 percent of contracted capacity.[43] As a result, SCE's assumption that 100 percent of contracted capacity will be provided substantially overestimates the cost-effectiveness ratios. Therefore, the already low TRC ratios SCE provides for the proposed day-ahead contracts are actually considerably overstated.

a. Benefit-Cost Ratios That Do Not Include Any T&D Benefits Are Better Indicators of Whether A Program Is Cost-Effective

SCE provided a sensitivity analysis of deferred T&D investment benefits, but admits that only a few programs meet the stringent "right place" and "right certainty" criteria.[44] SCE asserts that the aggregator contracts also "meet the 'right certainty' criteria for T&D benefits," but the lack of a track record of customer enrollment makes the "right place" criterion uncertain.[45] At hearings, SCE witness Carl Silsbee clarified there is no basis for establishing a numeric value for the T&D adder,[46] but that because the renegotiated contracts now contain terms and conditions that allow dispatch of the contracts for local reliability needs, the contracts can provide T&D benefits.[47]

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[43] Ex. 316 and C-316, p. 11.

[44] Ex. 1, p. 216, line 5-7, which states "only BIP and SDP offer the right certainty because those programs can be called independent of a generation event and can be implemented at a specific location."

[45] Ex. 1, p. 220, line 16 – p. 221, line 3.

[46] 2 RT 200, lines 8-10 (Silsbee/SCE)

[47] 2 RT 200, line 27 to 201, line 5 (Silsbee/SCE). SCE identified this new clause as Section 1.5 ("Local dispatchability") of the proposed contracts in 1 RT 50, lines 4-6 (Martinez/SCE).

The new language providing locational dispatch is contained in Section 1.5 of the proposed contracts, but how this dispatch will work operationally remains vague. SCE has not yet identified specific locations or specific circuits that meet the "right place" and "right certainty" criteria, nor has it presented evidence of whether SCE T&D planners will actually rely on these contracts to provide the necessary level of DR reductions and defer any potential T&D investments. In a similar vein, SCE assigns value to the new locational dispatch clause with regards to Local Resource Adequacy (the analysis for T&D benefits and Local RA both hinge on identifying where the DR customers are specifically located). Even with the additional term for local dispatch, it is not feasible for SCE to count these contracts towards Local RA as SCE has not yet mapped these resources to Local Areas (currently two in SCE's service territory: Los Angeles Basin and Big Creek/Ventura).[48] SCE does not explain the reasons for not conducting this mapping analysis, or whether it intends to do the analysis anytime soon.[49] Accordingly, the Commission should reserve judgment on the significance of this local dispatchability clause until SCE demonstrates its actual operational value.

Other parties' comments regarding the allocation of T&D benefits to DR programs emphasize the fact that meeting the "right place," "right time," and "right certainty" requirements will be a difficult task. While it conducted a sensitivity analysis of T&D benefits, PG&E states it has not conducted any analyses of whether or not specific DR programs, or subsets of such programs (e.g., a DR program customer or a group of DR customers located in a specific geographical area) provide a T&D benefit by allowing PG&E's T&D planners to confidently defer investments in T&D capacity in specific locations.[50] PG&E states,

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[48] Ex. 1, p. 204.

[49] 1 RT 48, line 3-10 (Reed/SCE).

[50] Ex. 311

> PG&E's T&D planners make investment decisions based upon forecasts of localized peak load derived from historical peak loads observed in those local areas. Thus DR programs are implicitly considered by T&D planners to the extent that their existence reduces historic peak loads. However, since DR programs are currently called primarily based upon system generation conditions, and not to address high peak loads in local planning areas, PG&E planners do not explicitly factor them into their decisions. In theory, this could be done, provided that the DR programs met the "right place," "right time," and "right certainty" conditions necessary for planners to have the confidence that they could reliably defer T&D investments for some period of time.[51]

In Prepared Testimony, CDRC witness William Monsen alleges it would be appropriate to include 50 to 100 percent T&D benefit into the cost-effectiveness calculations.[52] However, Mr. Monsen does not explain the basis of this statement. At hearings, Mr. Monsen admitted there would be very small or no benefits attributed to a group of DR participants located in a distribution planning area with excess T&D capacity.[53] Since the proposed contracts do not have any customers enrolled at the moment, it is impossible to predict where the customers will be located.

No party has justified the allocation of 100 percent T&D benefits, nor is there a compelling argument to assign even 50 percent T&D. Therefore, when considering the sensitivity analysis on cost-effectiveness, the Commission should assign no or very little deferred T&D benefit.

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[51] Id.

[52] Ex. 705, p. 25, lines 9-12.

[53] 3 RT 358, lines 8-11 (Monsen/CDRC).

b. Raising Incentives Is Not the Solution For Low Performing Resources That Have A Benefit-Cost Ratio Well Below 1.0

As discussed above, average compliance for all SCE contracts in 2007-08 during both test and non-test events are 41 percent of contracted capacity,[54] so the cost-effectiveness ratios regarding these programs should appear lower than reported. If the proposed day-ahead contracts perform at the same level as the existing ones, their cost-effectiveness is recalculated as xxxx for the EnergyConnect day-ahead contract, and xxxx for the ECS day-ahead contract.[55]

In defending the cost-effectiveness results of certain programs, SCE asserts, "a benefit-cost ratio below 1.0 does not necessarily imply that a program should be rejected but rather suggests that a program's incentive level may need to be adjusted in order to provide net positive benefits, if that is the Commission's objective."[56] Even though SCE lowered incentive levels of the contracts (i.e. capacity and/or energy prices) during renegotiation, xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx.

With regard to the two proposed day-ahead aggregator contracts, raising the incentive level through prices is not the solution. The performance of SCE's five existing aggregator contracts approved in D.08-03-017 and D.07-05-029 indicates that delivered load reductions will be much lower than projected load reductions.[57] For approximately ten months of the year, aggregator contracts are not called for an

[54] *See* Ex. 304, answer to Question 1.

[55] Ex. 316 and C-316, p. 12, line 9-10. Calculation based on zero T&D benefit.

[56] Ex. 7, p. 2, line 6-9.

[57] Ex. C-316, pp. 14-15.

event.[58] While it is true that the aggregator can potentially pay penalties for under-performance, SCE's settlement history of its existing third-party contracts shows that such penalties are negligible compared to the payments for unproven capacity that the aggregator receives during the year.[59] Therefore, raising incentives is not a solution to address the issue of non-performance, but rather suggests that other mechanisms need to be in place to provide adequate ratepayer protection.

One such example is a modification to the penalty provisions contained in the existing and proposed contracts. Currently, the penalty structure of the four proposed contracts is identical to the penalty provisions found in CBP.[60] The penalty structure encourages inferior performance because an aggregator continues to receive payments and is not penalized until its performance drops below 50 percent of the contracted capacity rate. The lack of incentive is evident by the history of unacceptable performance of the existing contracts.[61] Since penalties are not incurred until performance is well below failing, these contracts cost far more than they are worth.

In rebuttal, SCE asserts the payment/penalty structure has been approved and deemed reasonable by the Commission, after substantial vetting by DRA and SCE, in D.08-03-017.[62] It is true that the payment/penalty structure was approved in a prior decision, but at that time, bilateral agreements with aggregators were still novel to the IOU's DR portfolios, and the Commission had limited information regarding a prior track record of aggregator performance (other than EnerNOC's contract that was still ramping up at the time of SCE's application). DRA makes no specific recommendations regarding changes to the existing payment/penalty structure at this

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[58] *See* Ex. 304, answer to Question 1.

[59] *See* Ex. 316 and C-316, pp. 11-12.

[60] Ex. 7, p. 30, lines 26-32.

[61] *See* Ex. 316 and C-316, p. 14-16.

[62] Ex. 7, p. 24, lines 10-12.

time, although further experience with the utilities' existing contracts may indicate that the penalties are worth restructuring. As an alternative, DRA addresses the issue of performance (or lack thereof) in its recommendation regarding SCE's proposed "technical potential" clause to adjust capacity payments.

2. Ratepayers Are Not Adequately Protected Under SCE's Proposed "Technical Potential" Clause

The Commission approved two ASC contracts in D.08-03-017 that demonstrated superior cost-effectiveness under the Consensus Framework. The Commission reasoned, "Well designed performance incentives are an important factor in demand response programs, due to the imperative that the program operates as anticipated when called upon. The ASC Contracts are structured in such a way as to provide greater confidence that the demand response will appear when needed."[63] Given that average compliance of SCE's existing contracts in 2007-2008 is 41 percent, it is doubtful whether these contracts can still be considered "well designed."

SCE's proposed contracts offer new terms that it argues provide additional ratepayer protections. The "technical potential" clause[64] is one of the few differences between the proposed contracts and those rejected in D.08-03-017. This requires an aggregator to submit an *ex-ante* estimate of its capacity on a customer-by-customer level before the beginning of every month.[65]

SCE argues in rebuttal testimony that this mechanism represents a significant improvement in the management of third-party resources, in particular in ensuring that the contract resources are available for events, and deliverable when called under the conditions of dispatch.[66] However, SCE describes technical potential as being, in

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[63] D.08-03-017, p. 13.

[64] Ex. C-5, Appendix P (Clause 3.4 of each proposed contract).

[65] Ex. C-304, answer to Question 2.

[66] Ex. 7, p. 36.

principle, “a similar approach for adjustment of compensation” as the current process for determining adjusted capacity.[67] At hearings, SCE admitted that this is the same process it uses now to adjust capacity with its existing contracts.[68]

As Table 3-7 of the Prepared Testimony of Yuliya Shmidt demonstrates[69], SCE’s mechanism for adjusting capacity is not at all an accurate predictor of performance. In months where events are called, the capacity payment is based upon capacity actually delivered, but in 2007-2008, the average contract had only approximately two months per year in which events where called.[70] In months without events, the aggregator is paid a capacity payment based upon either contracted or adjusted capacity, whichever is lower. Table 3-7 demonstrates that six of the seven months with events had both contracted and adjusted capacities that vastly overestimated the ability of the aggregator to deliver load reduction.[71] As a result, ratepayers are generally overpaying aggregators in months that have no events.

Technical potential is an opaque process that does not allow the Commission to know exactly how “adjusted capacity” is calculated nor whether those calculations are based on good reasoning. The Commission cannot perform effective oversight because the mechanism is not transparent and capacity adjustments are not predictable.

In rebuttal testimony, SCE argues aggregators have not had adequate time to demonstrate their performance capabilities, and that because EnerNoc’s proposed contract is an extension of the existing contract, “ramp-up issues are expected to be

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[67] Ex. 316, p. 14, lines 6-7.

[68] 1 RT 45, lines 12-17 (Martinez/SCE).

[69] Ex. C-316

[70] Ex. 316, p. 15, line 5.

[71] *See* Ex. C-316, pp. 14-16.

negligible."[72] SCE ignores the fact that each existing and proposed contract allows for ramp-up issues by increasing contracted capacity slowly over a period of years. Therefore, ramp-up issues cannot be responsible for the contracts' poor performance.

The Commission should direct the utilities to require that all proposed third-party contracts contain provisions that adjust capacity payments based on an aggregators' most recent performance in a Test, Re-Test, or dispatch event to ensure that payments during the ramp-up period and beyond are commensurate with actual performance.

3. Price Comparison of the Day-Ahead to the Day-Of Contracts

In the instant case, SCE forecasts almost $70 million[73] for all four contracts, but provides no analysis on the reasonableness of the prices contained within the contracts.[74] SCE had believed the prices of all eight contracts proposed in A.07-10-013 were reasonable because they were the result of a competitive solicitation.[75] Still, the RFO process resulted in Commission rejection of four of the eight contracts, which suggests that a competitive solicitation does not necessarily result in good contracts.

Specifically, DRA takes issue with the prices proposed for the day-ahead aggregator contracts. Exhibit C-310A (DRA's aggregator comparison chart) shows xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxx. As explained above, given the history of low performance, SCE has not demonstrated that higher incentives are necessary to make the resource more reliable. In the proposed contracts, the bulk of the cost is contained in capacity

[72] Ex. 7, p. 36, lines 15-6; p. 37, lines 11-12.

[73] Ex. 1, p. 50, line 10.

[74] As mentioned above, DRA has reached a settlement in principle regarding SCE's proposed Day-Of contracts.

[75] 1 RT 38, lines 1-3 (Martinez/SCE).

payments (which are not performance-based) rather than energy payments (which are performance-based). xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx.

SCE's Capacity Bidding Program is the most similar DR program to the proposed agreements. The summer average capacity price for 1-4 hour event is $10.35 day-of, and $9.00 day-ahead.[76] Day-of options are priced higher because of the characteristics of the products' availability, and the timing in which it is called.[77] Likewise, any proposed aggregator contract should reflect higher prices for day-of resources than for day-ahead resources. DRA believes that the confidential nature of SCE's January 2007 RFO process caused this distinction to be lost, especially when the parties' in the RFO process did not know the prices and terms of other parties' offers. xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx

4. The Contracts Cannot Be Approved Based On Cost-Effectiveness At a Portfolio Level Nor For SCE's Need To Meet Its Demand Response Goals

SCE's rebuttal testimony states, "In D.08-03-017, the Commission considered eight (8) DR contracts proposed for approval by SCE, and ultimately approved those contracts that, as a portfolio, were cost effective."[78] SCE asserts that the Commission should continue to look favorably on a portfolio of DR contract resources that is forecast to provide cost-effective benefits for SCE's ratepayers.[79] SCE misstates the

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[76] Ex. 307, Sheet 3.

[77] 1 RT 42, line 24 to 43, line 3 (Martinez/SCE).

[78] Ex. 7, p. 32, lines 21-23.

[79] Id at p. 33, lines 20-22.

Commission's policy objective. In the same decision, the Commission clarified, "as the load impact protocols and cost effectiveness measures become more developed, we intend to move away from approval of demand response programs based on a portfolio approach."[80] Load impact protocols have been approved by the Commission in D.08-04-050. With the Consensus Framework proposed in R.07-01-041, a final framework for cost-effectiveness is also close to being resolved. It is time to move away from approving programs based on a portfolio approach.

In any case, the proposed contracts do not have stellar cost-effectiveness even on a portfolio basis. The portfolio cost-effectiveness of the four contracts is only 0.76 with no T&D benefit, and 0.91 with 50 percent T&D benefit.[81] Since no party justified the allocation of even 50 percent T&D benefit, the Commission should regard the 0.76 ratio as the more appropriate estimate even assuming the contracts provide 100 percent of their contracted capacity. Additionally, the portfolio cost-effectiveness of the ECI and ECS contracts is xxxxxxxxxxxxxxxxxxxxx

The Commission also cannot justify approval of the two day-ahead contracts based on SCE's need to meet its demand response goals. In D.08-03-017 the Commission stated,

> We did not, and do not now, intend for our demand response goals to be an open door through which any demand response program may enter, regardless of adherence to cost, reliability and related critical criteria. To the extent that the Contracts are appropriate based on such criteria as cost and reliability (or other appropriate criteria), the Contracts will help meet our demand response goals for SCE. To the extent that the Contracts do not meet our other criteria, we will not approve them simply to move toward these goals.[82]

[80] D.08-03-017, p. 14.

[81] Ex. 1, p. 221.

[82] D.08-03-017, p. 18.

This means that only after comprehensive evaluation of an *individual* proposed program's characteristics, the Commission can then determine whether it will be useful to meet demand response goals for SCE.

D. SDG&E's TA/TI Program Results Should Be Consistent with the Other Utilities

Unlike PG&E and SCE who appear to include TA/TI incentives only in their portfolio cost-effectiveness analysis, SDG&E presents TA/TI itself as a stand-alone program that includes avoided cost benefits of all DR programs enabled by TA/TI.[83] DRA is concerned that because of this mixing of costs and benefits of TA/TI, it is difficult to compare the IOUs' programs on a consistent basis. It is not clear how SDG&E will keep track of the customers participating in DR programs enabled by TA/TI separate and apart from customers participating in the same DR programs that are not enabled by TA/TI. In addition, when SDG&E reports *ex-post* results for a specific program, (*e.g.,* CBP) the part of the CBP program performance that is enabled by TA/TI may not be included in the *ex-post* results, as the part of the program's performance enabled by TA/TI will be buried under the "catch all" program performance of TA/TI program.

Therefore, DRA recommends the Commission require SDG&E to treat its TA/TI funds for cost allocation purposes on a consistent basis with PG&E and SCE in reporting its DR program results.

III. STATEWIDE PROGRAMS

A. Base Interruptible Program

1. Cost-Effectiveness

The utilities all demonstrate that the Base Interruptible Program (BIP) is cost-effective.[84] All three IOUs assign most of the avoided capacity benefits of a proxy

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[83] Ex. 314, pp. 38-39.

[84] Ex. 314, p. 17, Table 2-1.

combustion turbine (CT) to BIP in spite of the fact that the BIP program is an emergency-triggered program.

Both PG&E and SCE state the CT's allocation is based on a program's *ability* to displace Loss of Load Expectations (LOLE) events on a program's *availability*, and not whether a program is actually called or how frequently the program was called historically.[85] DRA questions the appropriateness of this assumption for BIP. Most of the Loss of Load Probability (LOLP) or LOLE hours do not correspond to CAISO declaring a Stage 2 Emergency, the current BIP trigger. Even with the proposed modification to change the BIP trigger to *prior to* a Stage 1 Emergency, the strict protocols proposed in the utilities' advice letters as to when BIP customers could be called, suggest it is likely to remain as a program callable only in case of an emergency. So for all practical purposes, a BIP program is not available to displace the LOLP or LOLE hours that a CT displaces. DRA therefore disagrees with the IOUs' assumption that a high LOLP or LOLE factor should be allocated to BIP. SDG&E allocates an LOLP factor of 98 percent to BIP.[86] SCE allocates an LOLP factor of 76 percent to BIP.[87] PG&E allocates 85.5 percent.[88] For such identical programs, the IOUs assume such widely different factors that DRA questions the consistency between the methodologies used by IOUs that produce such disparate numbers for LOLP.

2. Integration Into MRTU

Although the program appears cost-effective, DRA assigns BIP a Rank 3 due to the concern that the program, in its current form, cannot integrate into MRTU. PG&E's rebuttal testimony responds,

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[85] Ex. 314, p. 18.

[86] Ex. 112, p. 7.

[87] Ex. 1, Appendix C, p. 8.

[88] Ex. 314, p. 17, Table 2-1.

> A DR program can fit into MRTU by: (1) bidding into energy markets; (2) bidding into ancillary services markets; and/or (3) responding to emergencies. All involve legitimate participation in MRTU. No DR programs currently participate in all modes, however. BIP will be fully utilized in MRTU as it is currently designed. Neither MRTU nor MAP is negatively impacted.[89]

DRA disagrees. Emergency programs will not participate explicitly in the CAISO market in MRTU release 1, as it requires a manual "workaround" process to adjust the RUC[90] procurement target to account for DR. For DRA, "integration into MRTU" means that the resource can at least participate in CAISO's day-ahead market, as all other "non-emergency" DR programs do. Programs that are unable to participate in the day-ahead market do not allow the CAISO to avoid procurement of resources for customers enrolled in emergency programs. Even with the manual "work-around process," this results in potential Tier 1 RUC charges for all ratepayers, in addition to BIP programs costs and incentives.

What PG&E suggests is that BIP will continue to serve its current role of responding to emergencies. Draft Resolution E-4220 states the trigger change is only an "interim solution to a longstanding debate on how to best align emergency-triggered programs with CAISO operational practices."[91] Although no party doubts BIP's continued role as an emergency program under MRTU, it is hardly a step towards integration.

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[89] Ex. 202, p. 3-5, A7.

[90] Residual Unit Commitment (RUC) is a process within MRTU that procures resources based on the CFCD.

[91] Draft Resolution E-4220, p. 1.

3. DR Rulemaking Phase 3 Considerations

BIP, in its current (and proposed) form, may never fully integrate into MRTU, as it will only serve as an emergency program. The larger issue, however, is whether the Commission should allow the utilities to continue or increase the program in its current state, beyond what the Commission ultimately determines to be the appropriate size of such emergency programs. SCE intends to "continue to recruit customers to the BIP program," and expects "annual enrollment growth of 10 percent or about 60 accounts a year during the 2009-11 cycle."[92] PG&E intends to transition BIP into PeakChoice after 2009[93], and states it will file an advice letter after MAP is implemented if it appears advisable to terminate BIP at that time.[94] Based on PG&E's load impact estimates, it does not appear the utility intends to enroll additional customers nor does it expect an increase in MWs for the 2009-2011 cycle.[95] SDG&E's enrollment forecasts also indicate no program growth for the 2009-2011 cycle.[96]

The Commission's stated policy is to move from a reliance on emergency programs and to encourage price-response programs.[97] Phase 3 of the Order Instituting Rulemaking[98] will determine further refinements to emergency-triggered programs. To ensure consistency between Phase 3 of the rulemaking and the instant proceeding, DRA reiterates its concern:

> DRA has consistently argued that IOUs' emergency-triggered DR programs should be frozen at current levels

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[92] Ex. 1, p. 34, line 3 and 15.

[93] Ex. 201, p. 2-6, line 15.

[94] Ex. 201, p. 2-7, lines 26-28.

[95] *Id.* at p. 514 and 516. (Tables 5-3 and 5-4.)

[96] Ex. 103A, pp. 6-8.

[97] Draft Resolution E-4220, p. 3.

[98] R.07-01-041.

> while CAISO and IOUs seek ways to transition these programs from emergency type to price-responsive type DR. Fortunately, if the Commission does conclude that about 500-1,000 megawatts of emergency-triggered DR resources are necessary to avoid involuntary firm load shedding during serious system emergencies, only a portion of the current 1,700 megawatts of emergency-triggered DR will need to be transitioned to price-responsive DR.[99]

Accordingly, the Commission should direct the utilities to freeze BIP at current levels until it issues a final decision in Phase 3 of the DR Rulemaking. Further, the Commission should direct all utilities to file applications regarding program changes (including termination) with respect to a program's integration with MRTU. This is consistent with the August 7, 2008 ALJ Ruling, which stated:

> [S]ome IOUs suggest that program changes related to MRTU may be made in the future when MRTU requirements become more defined, potentially through advice letter filings. This is contrary to the process set out in the February Guidance Ruling, which orders IOUs to work with CAISO to understand expected MRTU requirements and propose programs in these applications that better align with MRTU as it is currently expected to operate. If further program changes are needed within the 2009-2011 period to take advantage of MRTU capabilities, the Guidance Ruling states that "IOUs may submit ***applications*** for new programs or program modifications for implementation during the 2009-2011 period. IOUs are directed to address compatibility of all programs with MRTU in their amended applications, and to keep in mind that the appropriate vehicle for future program changes will be a new application or a petition to modify a decision adopting the program, not an advice letter.

Because of questions regarding the cost-effectiveness methodology, multiple barriers towards integration, and pending determination of the size and program

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[99] *Response of the Division of Ratepayer Advocates* [to June 25, 2008 Comments of CAISO], p. 3, dated July 9, 2008.

design of emergency programs in Phase 3 of the Rulemaking, DRA assigns this program a Rank 3. DRA recommends the Commission conditionally approve the program in 2009, and require all IOUs to submit new applications to justify program continuation and progress towards integration with MRTU, as appropriate. Approval of the BIP program design and budgets for the entire three-year cycle would be an improper predetermination of the Phase 3 issues set forth in Rulemaking 07-01-041.[100]

B. Capacity Bidding Program

Based on a Rank 2 designation[101], DRA recommends the Commission approve the program for the 2009-2011 program cycle, but require all IOUs to submit advice letter filings to update the Commission on their progress to make the CBP program uniformly cost-effective across the three IOUs using consistent assumptions. The utilities should also update the Commission on the expected progress towards integration with MRTU, and file applications or petitions to modify, as appropriate. DRA agrees with SCE's proposal to transition CBP into its Energy Options program in 2010. DRA recommends PG&E also transition CBP to PeakChoice in 2010.[102]

C. Demand Bidding Program

DRA assigns DBP a Rank 2.[103] DRA recommends the Commission approve the program budgets for the 2009-2011 program cycle, but require all IOUs to submit advice letter filings to update the Commission on their progress to make the DBP program uniformly cost-effective across the three IOUs using consistent assumptions.

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[100] This is also consistent with Draft Resolution E-4220, which states, "The new trigger is an *interim* solution, as the DR Phase 3 of the OIR will make final determinations regarding emergency-triggered demand response program policy and the ultimate design of these programs." Draft Resolution E-4220, p. 4.

[101] *See* Ex. 314, pp. 21-24.

[102] *See* Ex. 314, p. 30.

[103] *See* Ex. 314, pp. 25-27.

The utilities should also demonstrate the expected progress towards integration with MRTU, and file applications or petitions to modify, as appropriate.

IV. OTHER ISSUES

A. Multiple Program Participation

DRA supports multiple program participation provided that the IOU addresses the concern that a customer should not be paid twice for the same load reduction.[104] PG&E proposes to achieve this objective by not paying incentives they determine are duplicative based on certain considerations.[105] SDG&E states it is important to establish process and safeguards governing multiple DR program participation so that customers do not receive multiple or duplicative incentives for the same load reduction, and that load reduction(s) are credited to the appropriate programs by virtue of a hierarchy of program precedence.[106] SCE, however, states that it is generally opposed to the same customer participating in multiple programs because, according to SCE, incentive payments for each program are based on the same avoided capacity costs; thus, resulting in excess payment.[107]

PG&E appears to resolve this concern. PG&E explains that typically, a customer can participate in one program that pays an incentive (usually monthly) for being on the program, and a pay-for-performance type program that only pays an incentive for load reduction during an event.[108] If such a program (e.g., CBP) is called concurrently with another pay-for-performance type program (e.g., DBP), both PG&E and SDG&E will decline payment for pay-for-performance of one of the two programs based on pre-established rules communicated to their customers.

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[104] Ex. 314, pp. 39-41.

[105] Ex. 201, p.2-24.

[106] Ex. 102A, p. MWW-74.

[107] Ex 1, p.14.

[108] Ex. 201, p.2-24.

Multiple program participation should be treated consistently among the three utilities. Therefore, DRA recommends the Commission direct SCE to allow dual participation of DR programs where available.

B. Inconsistent Inputs between IOUs' Statewide Programs

As noted above in the discussion above regarding the Base Interruptible Program, DRA is concerned that IOUs have made different input assumptions that eventually determine avoided cost benefits of DR programs. As shown in Table 2-9 of Exhibit 314, page 41, the three IOUs have used very different assumptions, making it difficult to compare the cost-effectiveness of the same programs across different IOUs. In future DR filings, DRA recommends the Commission require IOUs to use same assumptions for LOLP and avoided T&D benefits when comparing these statewide programs.

C. PG&E's Proposal To Utilize The Advice Letter Process To Replace Existing Aggregator Contracts Was Denied In D.06-11-049

PG&E requests to file an RFP to replace the expiring PG&E Aggregator ("AMP") contracts in 2011 in this application.[109] PG&E seeks Commission approval of the contracts selected through the RFP process via filing an advice letter, rather than through an application. Since aggregator contracts could carry potentially substantial risks to ratepayers, the issues raised are often controversial in nature and the cost is often very high, contract approval is more appropriately addressed through an application process. PG&E made a similar request to approve aggregator contracts through an advice letter process in A.05-06-066. The Commission rejected this request in D.06-11-049, saying, "We agree…that the advice letter process would not provide the Commission and intervenors an opportunity to evaluate proposals. Each

[109] Ex. 201, p. 2-15.

utility should file an application with the Commission requesting approval for specific contracts."[110]

Therefore, DRA recommends the Commission require PG&E to file an application rather than an advice letter when PG&E seeks approval of new AMP contracts in 2011. DRA also recommends PG&E work closely with the Commission when issuing its RFP. Improvements to the RFP process are needed, such as: transparency in other parties' offers for day-ahead or day-of options, total number of MW, and prices, while maintaining confidentiality of parties' identities. As lessons learned from SCE's January 2007 RFO, DR Bilateral Solicitation, such features may result in more economical proposals and place more confidence in the competitive process.

D. PG&E's Fund Shifting Proposal Should Be Rejected

PG&E requests full discretion to shift funds between programs within the same budget category. This request was rejected in the utilities' Motion for Bridge Funding in D.08-12-038: "We conclude that it is neither necessary nor appropriate to change the existing fund-shifting rule at this time, especially without a more thorough review than is possible here of the implications of the proposed modification, which could allow IOUs to discontinue individual demand response activities unilaterally."[111] DRA recommends the Commission approve fund shifting under the current rules (utilities may reallocate up to 50% of funds between programs within a budget category), consistent with this decision and D.06-03-024.[112]

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[110] D.06-11-049, p. 44.

[111] D.08-12-038, p. 27.

[112] D.06-03-024, p. 13.

V. CONCLUSION

For the reasons discussed above, DRA's proposals are reasonable and are consistent with the Commission's policies on demand response. Accordingly, the Commission should adopt DRA's ranking mechanism and proposals set forth in this opening brief.

Respectfully submitted,

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January 28, 2009

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of **OPENING BRIEF OF THE DIVISION OF RATEPAYER ADVOCATES **REDACTED VERSION**** in A. 08-06-001 et al by using the following service:

[X] **E-Mail Service:** sending the entire document as an attachment to all known parties of record who provided electronic mail addresses.

[ ] **U.S. Mail Service:** mailing by first-class mail with postage prepaid to all known parties of record who did not provide electronic mail addresses.

Executed on January 28, 2009 at San Francisco, California.

/s/ NANCY SALYER
Nancy Salyer

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address and/or e-mail address to insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

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